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GREENHOUSE GAS ABATEMENT WITH DISTRIBUTED GENERATION IN CALIFORNIA'S COMMERCIAL BUILDINGS[1]

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Abstract

Lawrence Berkeley National Laboratory (LBL) is working with the California Energy Commission (CEC) to determine the role of distributed generation (DG) in greenhouse gas reductions. The impact of DG on large industrial sites is well known, and mostly, the potentials are already harvested. In contrast, little is known about the impact of DG on commercial buildings with peak electric loads ranging from 100 kW to 5 MW. We examine how DG with combined heat and power (CHP) may be implemented within the context of a cost minimizing microgrid that is able to adopt and operate various smart energy technologies, such as thermal and photovoltaic (PV) on-site generation, heat exchangers, solar thermal collectors, absorption chillers, and storage systems. We use a mixed-integer linear program (MILP) that has the minimization of a site's annual energy costs as objective. Using 138 representative commercial sites in California (CA) with existing tariff rates and technology data, we find the greenhouse gas reduction potential for California's commercial sector. This paper shows results from the ongoing research project and finished work from a two year U.S. Department of Energy research project. To show the impact of the different technologies on CO_2 emissions, several sensitivity runs for different climate zones within CA with different technology performance expectations for 2020 were performed. The considered sites can contribute between 1 Mt/a and 1.8 Mt/a to the California Air Resources Board (CARB) goal of 6.7Mt/a CO_2 abatement potential in 2020. Also, with lower PV and storage costs as well as consideration of a CO_2 pricing scheme, our results indicate that PV and electric storage adoption can compete rather than supplement each other when the tariff structure and costs of electricity supply have been taken into consideration. To satisfy the site's objective of minimizing energy costs, the batteries will be charged also by CHP systems during off-peak and mid-peak hours and not only by PV during sunny on-peak hours.

1. Introduction

A microgrid is defined as a cluster of electricity sources and (possibly controllable) loads in one or more locations that are connected to the traditional wider power system, or macrogrid, but which may, as circumstances or economics dictate, disconnect from it and operate as an island, at least for short periods (see Microgrid Symposium 2005, 2006, and Hatziargyriou et al. 2007). The successful deployment of microgrids will depend heavily on the economics of distributed energy resources (DER), in general, and upon the early success of small clusters of mixed technology generation, grouped with storage, and controllable loads.

The potential benefits of microgrids are multi-faceted, but from the adopters' perspective, there are two major groupings: 1) the cost, efficiency, and environmental benefits (including possible emissions credits) of combined heat and power (CHP), and 2) the power quality and reliability (PQR) benefits of on-site generation and control.

[1] The work described in this paper was funded by the Office of Electricity Delivery and Energy Reliability, Distributed Energy Program of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231 as well as by the California Energy Commission (CEC).

In previous work, the Berkeley Lab has developed the Distributed Energy Resources Customer Adoption Model (DER-CAM), (Siddiqui et al. 2003 and Stadler et al. 2008). Its optimization techniques find both the combination of equipment and its operation over a typical year that minimize the site's total energy bill or CO_2 emissions, typically for electricity plus natural gas purchases, as well as amortized equipment purchases. The chosen equipment and its schedule should be economically attractive to a single site or to members of a microgrid consisting of a cluster of sites. A common assumption in the scientific community is that photovoltaic (PV) and batteries can supplement each other and contribute to less CO_2 emissions since renewable energy could be stored in the battery and used during night hours. We will pay special attention to that assumption and show that it is a rough assumption which neglects important economic boundaries. We will see that storage systems will also discharge during times when solar energy is available. Additionally, current piece meal practices in system design are not very useful to find the optimal solution. The energy flows in a building are complex enough that it is nearly impossible to find the best economic as well as environmental solution by trial-and-error approaches, and therefore, integrated approaches that consider the whole set of possible technologies are necessary.

This paper reports on the latest efforts to estimate the impact of CHP systems on CO_2 emission reduction potential in the state of California by using DER-CAM. The impact of DG on large industrial sites is well known, and mostly, the potentials are already harvested (see also Darrow et al. 2009). The commercial sector, especially in the midsize range of 100 kW to 5 MW electric peak loads, is widely overlooked. Only 150 MW of CHP capacities are currently installed in that sector (see also Combined Heat and Power Installation Database 2008). Prime candidates for CHP installations are office buildings, hospitals, colleges, and hotels because of their simultaneous need of electricity, heating and cooling, which can favor CHP systems with absorption chillers that use heat for cooling (see also Stadler et al. 2009 and Marnay et al. 2008). We looked to the California Commercial End-Use Survey (CEUS) database, which contains information on 2790 premises throughout California (for more information, see section 3 and CEUS), in order to gather building end-use data. And while it is theoretically possible to simulate and solve for all 2790 premises, it is computationally expensive to do so; therefore, 138 CA sites[2] in different climate zones between 100 kW and 5 MW electric peak load were selected to be representatives for the commercial sector. This assumption represents roughly 35% of the commercial electricity demand in CA. For those selected buildings, the total DER-CAM run time is less than 12 hours, which allowed for easily performing sensitivities. For this research, more than 25 sensitivity runs with different technology costs, tariffs, interest rates, incentive levels, etc. have been performed. The major results for as a whole as well as a more detailed analysis for the sunny San Diego Gas and Electric (SDG&E) service territory are shown. The major results are reported relative to the California Air Resources Board (CARB) goal of 4 MW incremental CHP in 2020 for the *entire* commercial sector. The Global Warming Solutions Act of 2006 (AB 32) requires CARB to prepare a scoping plan to achieve reductions in greenhouse gas (GHG) emissions in California (see also CARB 2009) and does consider CHP as an option.

2. The Distributed Energy Resources – Customer Adoption Model (DER-CAM)

DER-CAM (Stadler et al. 2008) is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS). Its objective is to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site, including utility electricity and natural gas purchases, amortized capital and maintenance costs for distributed generation (DG) investments. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments[3]. Furthermore, the model choice considers the simultaneity of the building cooling problem; that is, results reflect the benefit of displacement of electricity demand by heat-activated cooling that lowers building peak load and,

[2] Hospitals, colleges, schools, restaurants, warehouses, retail stores, groceries, offices, and hotels in different sizes.

[3] End-use efficiency investments, which are currently under design, are not considered in this paper (see also Stadler 2009b).

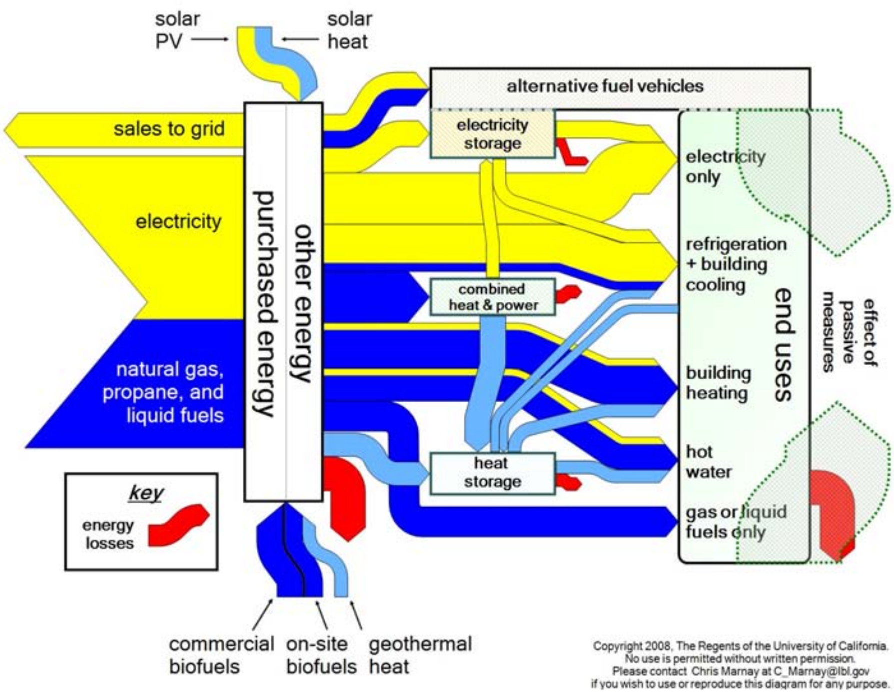
therefore, the generation requirement. Site-specific inputs to the model are end-use energy loads,[4] electricity and natural gas tariff structure and rates, and DG investment options. The following technologies are currently considered in the DER-CAM model:

- natural gas-fired reciprocating engines, gas turbines, microturbines, and fuel cells;
- photovoltaics and solar thermal collectors;
- electrical storage, flow batteries, and heat storage;
- heat exchangers for application of solar thermal and recovered heat to end-use loads;
- direct-fired natural gas chillers; and
- heat-driven absorption chillers.

Figure 1 shows a high-level schematic of the energy flow modeled in DER-CAM. Available energy inputs to the site are solar radiation, utility electricity, utility natural gas, biofuels, and geothermal heat. For a given site, DER-CAM selects the economically or environmentally optimal combination of utility electricity purchase, on-site generation, storage and cooling equipment required to meet the site's end-use loads at each time step. The end-uses are as follows:

- electricity-only loads, e.g. lighting and office equipment;
- cooling loads that can be met either by electricity powered compression or by heat activated absorption cooling, direct-fired natural gas chillers, waste heat or solar heat;
- hot-water and space-heating loads that can be met by recovered heat or by natural gas;
- natural gas-only loads, e.g. mostly cooking that can be met only by natural gas.

Figure 1. Schematic of Energy Flow Model Used in DER-CAM



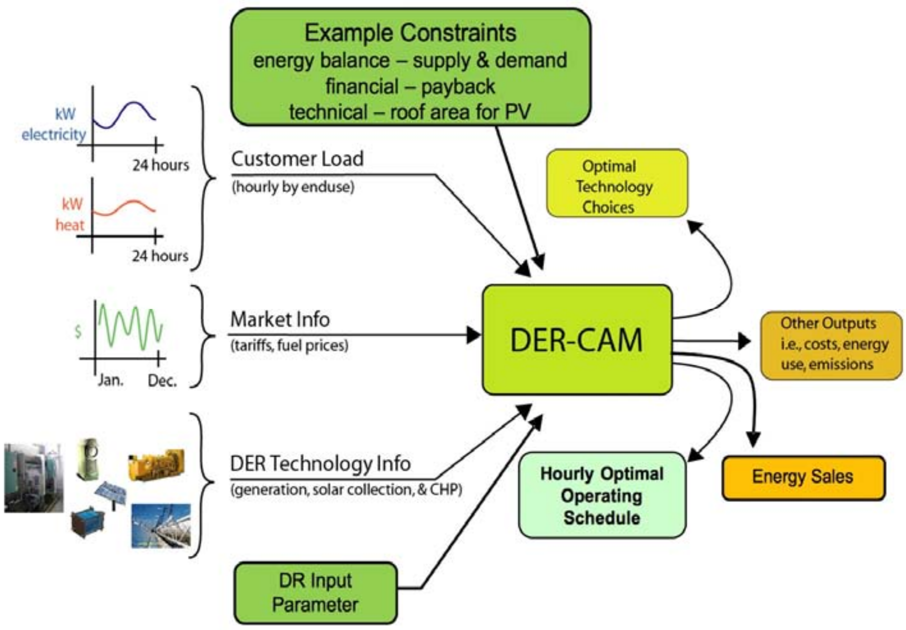
The outputs of DER-CAM include the optimal DG and storage adoption and an hourly operating schedule, as well as the resulting costs, fuel consumption, and CO_2 emissions (Figure 2).

[4] Three different day-long profiles are used to represent the set of daily profiles for each month: weekday, peak day, and weekend day. DER-CAM assumes that three weekdays of each month are peak days.

Optimal combinations of equipment involving PV, thermal generation with heat recovery, thermal heat collection, and heat-activated cooling can be identified in a way that would be intractable by trial-and-error enumeration of possible combinations. The economics of storage are particularly complex, both because they require optimization across multiple time steps and because of the influence of tariff structures (on-peak, off-peak, and demand charges). Note that facilities with on-site generation will incur electricity bills more biased toward demand (peak power) charges and less toward energy charges, thereby making the timing and control of chargeable peaks of particular operational importance.

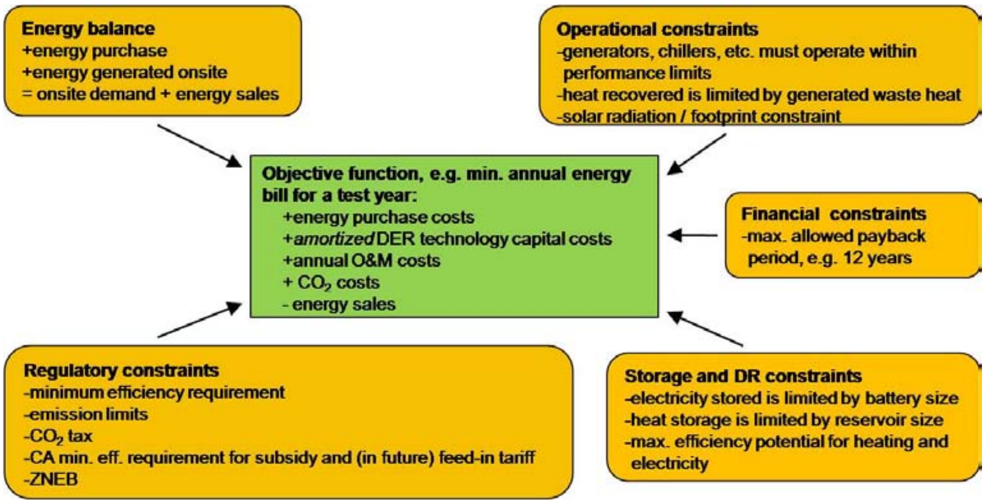
To make DER-CAM more complete and holistic, a demand-side-management (DSM) module is under design (however, it was not applied in this work). As can be seen from Figure 1, the end-uses can be directly influenced by efficiency / passive measures and demand reduction measures. Please note that batteries act as load shifting measures, and therefore, they are considered in this paper. For more information on the DSM module see Stadler 2009b.

Figure 2. High-Level Schematic of Information Flow in DER-CAM



The MILP solved by DER-CAM is shown by the diagram in Figure 3. In minimizing the site's objective function, DER-CAM also has to take into account various constraints. Among these, the most fundamental ones are the energy-balance and operational constraints, which require that every end-use load has to be met and that the thermodynamics of energy production and transfer are obeyed. The storage constraints are essentially inventory balance constraints that state that the amount of energy in a storage device at the beginning of a time period is equal to the amount available at the beginning of the previous time period plus any energy charged minus any energy discharge minus losses. Finally, investment and regulatory constraints may be included as needed. A limit on the acceptable simple payback period is imposed to mimic typical investment decisions made in practice. Only investment options with a payback period less than 12 years are considered for this paper. For a complete mathematical formulation of the MILP with energy storage solved by DER-CAM, please refer to Stadler et al. 2008.

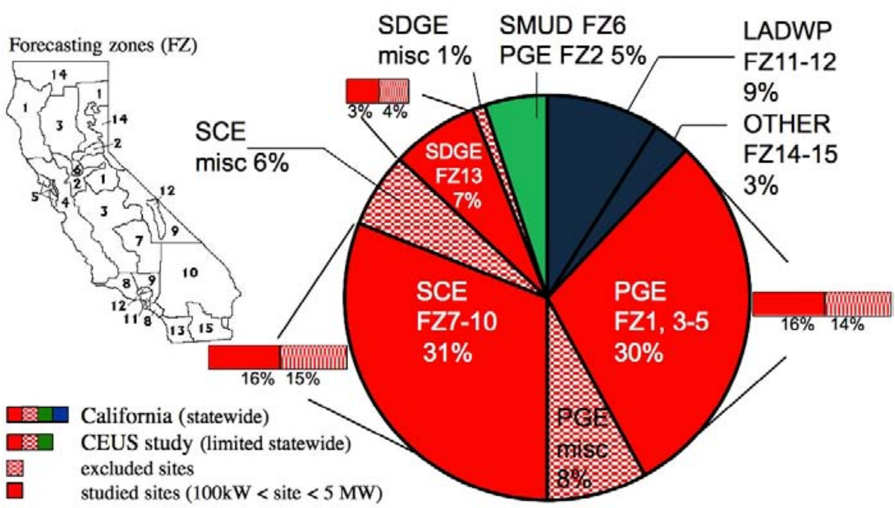
Figure 3. MILP Solved by DER-CAM[5]



3. Data Used in this Study

The starting point for the load profiles used within DER-CAM is the California Commercial End-Use Survey (CEUS) database which contains 2790 premises in the Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego and Gas Electric (SDG&E), and Sacramento Municipal Utility District (SMUD) areas (red and green areas of the pie in Figure 4). Additionally, not all climate zones and related utility territories are favourable for DG / CHP in the 100 kW to 5 MW range, so they were exclude from our study (PG&E FZ2 and SMUD FZ6). Finally, after eliminating the miscellaneous building types, which are hard to simulate since no information about their building characteristics is available, 68% of the total commercial electric demand is available in principle ("limited statewide" in Figure 4). However, since we are only interested in midsized buildings (excluding commercial sites under 100 kW or over 5 MW), we ultimately end up with 35% of the total commercial electric demand in the PG&E, SCE, and SDG&E service territories and the corresponding climate forecasting zones of FZ1, FZ3, FZ4, FZ5, FZ7, FZ8, FZ9, FZ10, and FZ13 (see also CEUS database at http://capabilities.itron.com/ceusweb/).

Figure 4. Considered Commercial Electric Demand



[5] Not all constraints are shown (e.g. flow batteries have more different constraints than electric storage).

The menu of available equipment options, their cost and performance characteristics, and example applicable SDG&E tariffs for this DER-CAM analysis are shown in Table 1, 2, and 3. Technology options in DER-CAM are categorized as either continuously or discretely sized. This distinction is important to the economics of DER because some equipment is subject to strong diseconomies of small scale. Continuously sized technologies are available in such a large variety of sizes that it can be assumed that close to optimal capacity could be implemented, e.g., storage. The installation cost functions for these technologies are assumed to consist of an unavoidable cost (intercept) independent of installed capacity that represents the fixed cost of the infrastructure required to adopt such a device, plus a variable cost proportional to capacity. As is typical for Californian utilities, the electricity tariff has time-of-use (TOU) pricing for both energy and power (demand charge). Demand charges are proportional to the maximum rate of electricity consumption (kW), regardless of the duration or frequency of such consumption over the billing period. Demand charges may be assessed daily (e.g. for some New York DG customers) or monthly (more common) and may be for all hours of the month or only certain periods (e.g. on, mid, or off peak), or hit just at the hour of peak system-wide consumption.

There are five demand types in DER-CAM applicable to daily or monthly demand charges:

- Non-coincident: incurred by the maximum consumption in any hour.
- On-peak: incurred only during on-peak hours.
- Mid-peak: incurred only during mid-peak hours.
- Off-peak: incurred only during off-peak hours.
- Coincident: based only on the hour of peak system-wide consumption.

The demand charge in $/kW is a significant determinant of technology choice and sizing of distributed generation and electric storage system installations (Stadler et al. 2008). For PG&E service territory three different tariffs were used (see also PG&E A-1, PG&E A-10, and PG&E E-19):

- electric peak load 0 – 199 kW: flat tariff A-1, no demand charge, seasonal difference between winter and summer months is a factor of 1.45
- electric peak load 200 kW – 499 kW: TOU tariff A-10, seasonal demand charge
- electric peak load 500 kW and above: TOU tariff E-19, seasonal demand charge.

For SCE service territory also three different tariffs were used (see also SCE GS-2, SCE TOU-GS-3, SCE TOU-8):

- electric peak load 20 – 200 kW: flat tariff GS-2, no demand charge, seasonal difference between winter and summer months is a factor of 1.1
- electric peak load 200 kW – 500 kW: tariff TOU-GS-3, seasonal demand charge
- electric peak load 500 kW and above: tariff TOU-8, seasonal demand charge.

Table 1. Menu of Available Equipment Options in 2020, Continuous Investments

	thermal storage	**lead acid batteries**	**absorption chiller**	**solar thermal**	**photo-voltaics**
intercept costs (US$)	10000	295	93912	0	3851
variable costs (US$/kW or US$/kWh)	100 US$/kWh	193 US$/kWh	685 US$/kW[6]	500 US$/kW	3237 US$/kW
lifetime (a)	17	5	20	15	20

Sources: Firestone 2004, EPRI-DOE Handbook 2003, Mechanical Cost Data 2008, SGIP 2008, Stevens and Corey 1996, Symons and Butler 2001, Electricity Storage Association, own calculations

[6] In kW electricity of an equivalent electric chiller.

Table 2. Menu of Available Equipment Options in 2020, Discrete Investments[7]

	capacity (kW)	installed costs (US$/kW)	installed costs with heat recovery (US$/kW)	variable maintenance (US$/kWh)	electric efficiency (%), (HHV)	lifetime (a)
ICEsmall	60	2721		0.02	0.29	20
ICE-med	250	1482		0.01	0.30	20
GT	1000	1883		0.01	0.22	20
MT-small	60	2116	na	0.02	0.25	10
MT-med	150	1723		0.02	0.26	10
FC-small	100	2382		0.03	0.36	10
FC-med	250	1909		0.03	0.36	10
ICE-HX-small	60		3580	0.02	0.29	20
ICE-HX-med	250		2180	0.01	0.30	20
GT-HX	1000		2580	0.01	0.22	20
MT-HX-small	60		2377	0.02	0.25	10
MT-HX-med	150		1936	0.02	0.26	10
FC-HX-small	100	na	2770	0.03	0.36	10
FC-HX-med	250		2220	0.03	0.36	10
MT-HX-small-wSGIP[8]	60		2217	0.02	0.25	10
MT-HX-med-wSGIP	150		1776	0.02	0.26	10
FC-HX-small-wSGIP	100		2270	0.03	0.36	10
FC-HX-med-wSGIP	250		1720	0.03	0.36	10

Sources: Goldstein et al. 2003, Firestone 2004, SGIP 2008, own calculations

Table 3. Estimated SDG&E Commercial Energy Prices in 2020

Electricity	Summer (May – Sep.)		Winter (Oct. – Apr.)	
	electricity (US$/kWh)	**demand (US$/kW)**	**electricity (US$/kWh)**	**demand (US$/kW)**
non-coincident	na	12.80	na	12.80
on-peak	0.13	13.30	0.13	4.72
mid-peak	0.11		0.12	
off-peak	0.08		0.09	
fixed (US$/month)	232.87/58.22[9]			

Natural Gas	
0.03	US$/kWh
112.18/ 11.22[10]	fixed (US$/month)

Source: SDG&E Tariffs and own calculations[11]

summer on-peak: 11:00 – 18:00 during weekdays
summer mid-peak: 06:00 – 11:00 and 18:00 – 22:00 during weekdays
summer off-peak: 22:00 – 06:00 during weekdays and all weekends and holidays
winter mid-peak: 06:00 – 17:00 during weekdays
winter off-peak: 20:00 – 06:00 during weekdays and all weekends and holidays

[7] ICE: Internal combustion engine, GT: Gas turbine, MT: Microturbine, FC: Fuel cell, HX: Heat exchanger. Technologies with HX can utilize waste heat for heating or cooling purposes.

[8] wSGIP: Considers the California self generation incentive program, which is basically an investment subsidy.

[9] Customers with an electric peak load above 500kW pay $232.87/month. Customers with an electric peak load less than 500kW pay $58.22/month.

[10] Customers with a natural gas consumption above 615,302 kWh/month pay $112.18/month. Customers with a natural gas consumption less than 615,302 kWh/month pay $11.22/month.

[11] For all runs the average natural gas price between 2006 and 2008 is used as an estimate for 2020, and therefore, this also considers the spike in natural gas prices in 2008.

For an estimate about the used marginal macrogrid CO_2 emission rates in California in 2020, please see Appendix A. The solar data necessary for PV and solar thermal simulation were gathered from NREL's PVWATTS.

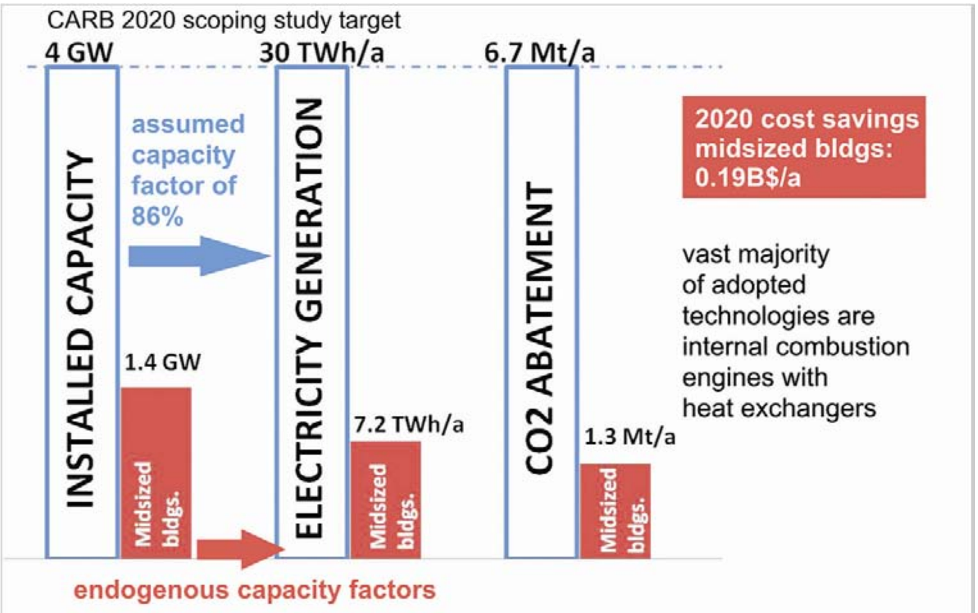
4. Major Results for 2020

4.1. Reference Case Results

Using data and assumptions described in the previous section, this study estimates that the midsized commercial building sector can install 1.4 GW of economic CHP capacity towards the 4 GW CARB goal. Coincidentally, medium-sized buildings with roughly 35% of the total commercial electric demand contribute a similar amount to the 4 GW goal. However, the CARB study assumes a fixed high capacity factor of 86%, which results in a 30 TWh/a goal. By using DER-CAM, which calculates capacity factors endogenously, the estimated average capacity factor is only approximately 60%. This lower capacity factor results in a lower electricity contribution, just 24%, towards the CARB CHP of 7.2 TWh/a. Finally, because of the low capacity factors and assumed macrogrid CO_2 emissions in 2020 (see appendix A), the CO_2 reduction potential is just 19% of the goal. However, because only economic adoption occurs under strictly cost minimizing optimization, the sample buildings can reduce their annual energy bill, which includes amortized investment costs, by $190M/a. Also, the results indicate that internal combustion engines (ICE) with heat exchanger (HX) are a strongly dominant technology even in 2020. Please note that these calculations also consider solar thermal and PV, but they are mostly dominated by ICEs. In this case 183 MW of PV and 416 MW of solar thermal are adopted and considered in the CO_2 number of Figure 5. Also, no storage systems are adopted since their costs are prohibitive.

These results demonstrate that a high fixed assumed capacity factor results in overly optimistic CO_2 abatement estimates because they do not capture the economics of a microgrid, including the possibility of curtailing engines when they are not economically attractive or when they are in competition with PV and/or solar thermal during the day.

Figure 5. Midsized Commercial Building Contribution to the CARB 2020 Goal, Reference Case

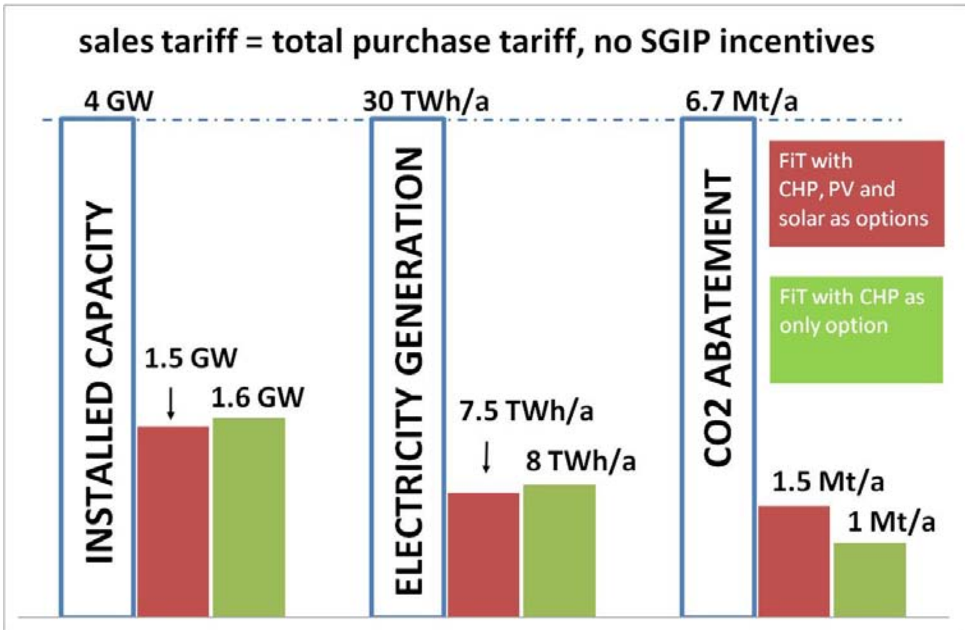


4.2. Feed-in Tariff Results

The impact of a CHP only feed-in tariff (FiT) is shown by the results of two scenarios presented in Figure 6. Assuming a FiT that allows sales back to the macrogrid at price slightly below the purchase price (pure net-metering) and without the Self Generation Incentive Program (SGIP), which is basically an investment cost buy down, the FiT has only a moderate impact on installed CHP capacity. The majority of adopted CHP systems are also ICE with HX and the FiT does not effectively favor fuel cells. The opportunity of selling into the macrogrid favors more efficient generating technologies such as fuel cells, but in this case not enough to incent more deployment. As can be seen from Figure 6 the FiT increases the energy production from CHP systems compared to the reference case from Figure 5, and yet carbon abatement is lower (green bar in Figure 6).

A second FiT scenario was performed in which solar thermal and PV are included. In this case, solar contributes to higher total DG energy output, although CHP is slightly reduced to 7.5 TWh/a. In this case, 423 MW of PV and 329 MW of solar thermal are adopted, which is reflected in the CO_2 number of Figure 6.

Figure 6. Midsized Commercial Building Contribution to the CARB 2020 Goal, Using a Feed-in Tariff Equal to the Purchase Tariff

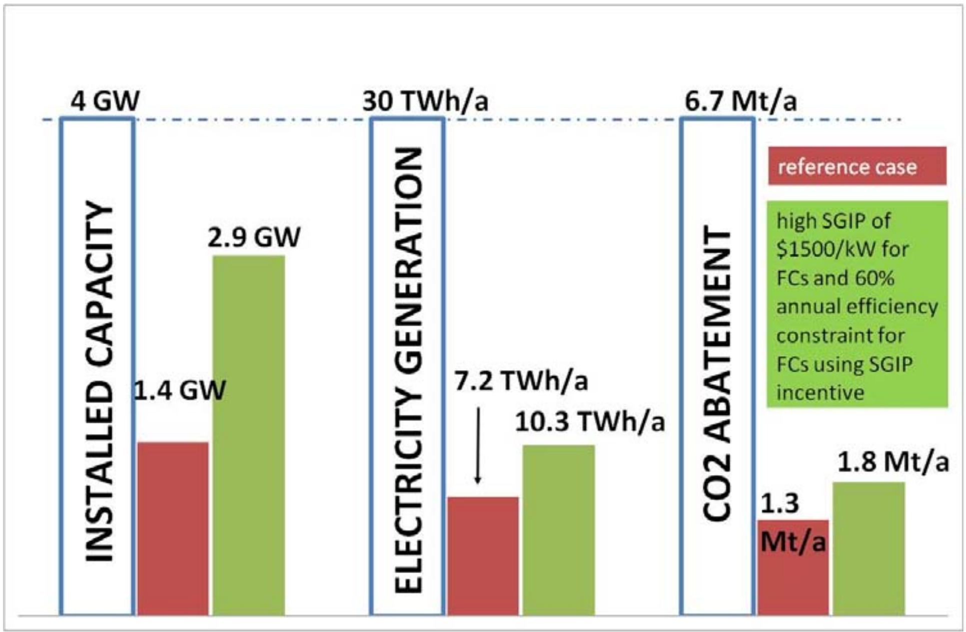


The reason for the limited CO_2 emission reduction potential is that ICEs have a low conversion efficiency of roughly 30%, which is even lower than the macrogrid efficiency of 34%. Increasing the electricity production due to electric sales without increasing the opportunity to utilize all the waste heat just reduces overall energy efficiency. The higher the FiT, the more sites act as power plants with low efficiency. To achieve significant CO_2 emission reductions in this circumstance it is necessary to use CHP technologies with a higher electric efficiency or add an efficiency or power limit.

4.3. High Self Generation Incentive Program (SGIP) Case Results

This scenario considers the impact of a high investment subsidy of $1500/kW for fuel cells (FCs) that operate with an electric efficiency above the macrogrid efficiency. Results are shown in Figure 7. It is assumed that to qualify for the $1500/kW SGIP subsidy the FCs must operate with a minimum total annual efficiency of 60%. This combination has a tremendous impact on CHP adoption as well as CO_2 reduction potential. Almost 73% of the 4 MW CARB goal is achieved by midsized commercial buildings. Also, the annually electricity production from CHP systems soars to 10.3 TWh/a. Due to the usage of more efficient FCs and the annual efficiency constraint this sensitivity run delivers the highest CO_2 reduction potential for CA. Please note that the installed PV capacity is reduced to 95 MW and the solar thermal capacity is reduced to 247 MW in this run.

Figure 7. Midsized Commercial Building Contribution to the CARB 2020 Goal, Using a $1500/kW SGIP for Fuel Cells

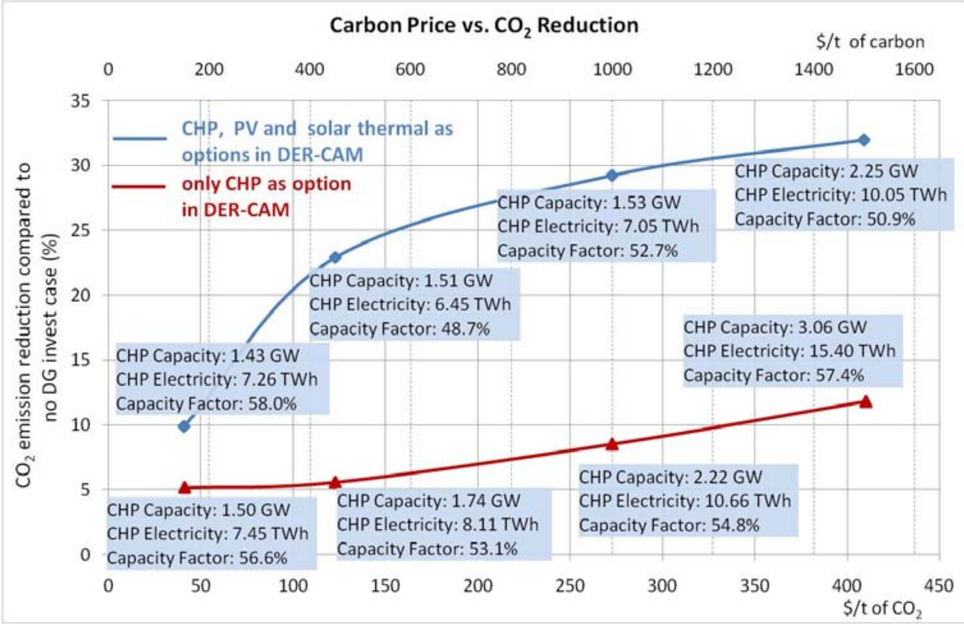


4.4. The Influence of a CO_2 Pricing Scheme

As shown in the previous section there is competition between FCs and PV / solar thermal. Does this competition between FCs and PV / solar thermal change if natural gas is made more expensive by a CO_2 pricing scheme? Figure 8 shows the CO_2 reduction compared to a do-nothing case without any investments in DG. With CHP, PV, and solar thermal as possible options, the CO_2 reduction increases very rapidly, but shows a saturation at high CO_2 prices, partly due to limited space for PV and solar thermal in commercial buildings[12]. However, most interesting is the fact that CHP adoption also increases with increasing CO_2 prices (see red line in Figure 8). With increasing CO_2 prices, more and more ICEs are replaced by efficient FCs.

[12] The PV and solar thermal area constraint within DER-CAM and the used data for this study are subject to further research.

Figure 8. Influence of a CO_2 Pricing Scheme



5. Sensitivity Results for SDG&E for 2020

Besides the overall major results for the state of California four different sensitivity runs for the SDG&E service territory were performed and the results are shown in Table 4. The base case run[13] does not consider any CO_2 pricing scheme and shows the dominance of ICE with HX even in 2020. No solar thermal system is used to supply an absorption chiller for building cooling. No storage systems are picked due to their prohibitive price.

In the CO_2 price run, a CO_2 price of \$123/tCO_2 increases the adopted solar thermal systems to approximately 77 MW and 53 MW are used in combination with absorption chillers. However, the CO_2 price also increases the number of installed FCs and reduces the number of ICEs. The results in Table 4 also show that the medium CO_2 price favors PV over solar thermal systems.

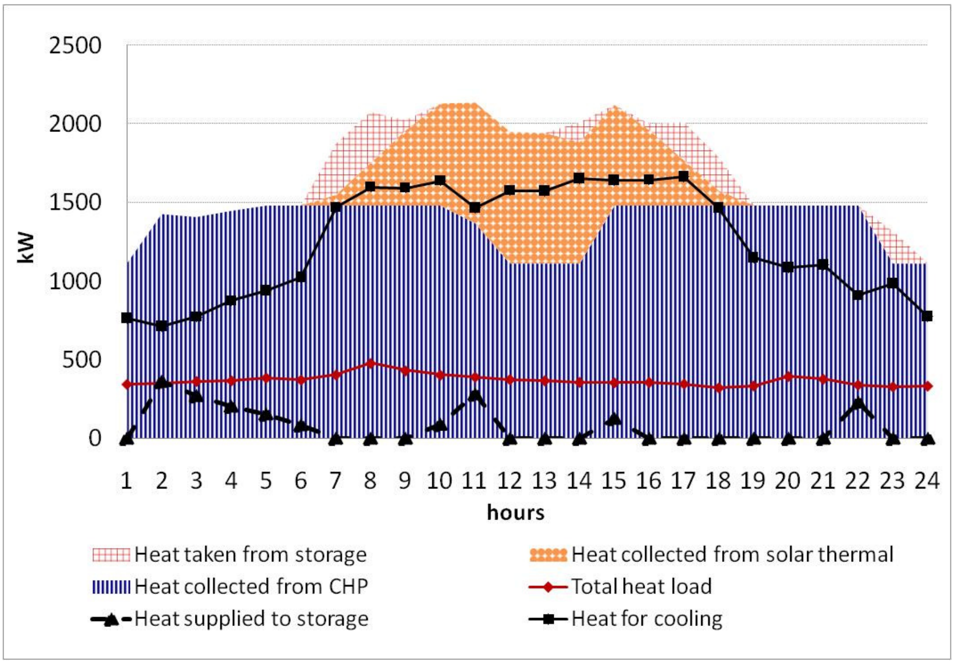
To make solar thermal systems more attractive, a high absorption chiller coefficient of performance (COP) of 1.2 instead of the baseline 0.7 is used in the last two sensitivity runs. This results in increased solar thermal adoption and reduced PV adoption, but ICEs are still very dominant. The office building example from Figure 9 shows that cooling is necessary all day long and the absorption chiller is supplied by waste heat from CHP units as well as solar thermal during on-peak hours (heat for cooling in Figure 9). In the last run, a 30% investment subsidy for heat storage as well as a 48% investment subsidy[14] for lead acid batteries is given and this brings storage into the solution. This fourth case shows the highest CO_2 reduction (~33%) as well as annual energy bill saving (~23%) compared to a no-invest case[15] without any DG technologies. However, the study shows that frequently non-solar energy is used for charging the storage (see Figure 9 and 10), and that due to cost minimization, the storage discharges even around noon hours.

[13] The base case run shows the SDG&E results from the reference case from section 4.
[14] Intercept costs for heat and electric storage are set to zero.
[15] Please note that the no-invest cases are not shown here and vary depending on the CO_2 price.

Table 4. Sensitivity Results for SDG&E Service Territory

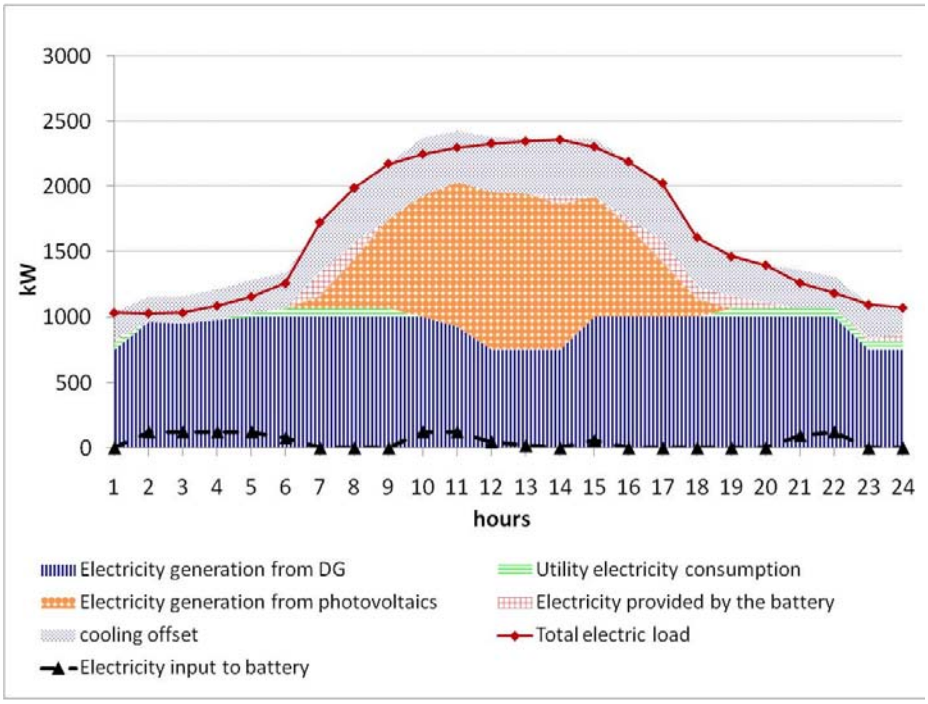
Results	base case (no CO_2 price)	CO_2 price	CO_2 price, high COP	CO_2 price, high COP, cheap storage
adopted solar thermal (MW)	3	77	344	296
solar thermal for absorption cooling (MW)	0.0	53	302	232
adopoted heat storage (MWh)	0.0	0.0	0.0	440
adopoted lead acid batteries (MWh)	0.0	0.0	0.0	370
adopted PV (MW)	73	495	356	387
adopted FC with HX (MW)	0.0	63	12	17
adopted ICE with HX (MW)	462	354	445	451
annual electricity displaced due to absorption building cooling (GWh/a)	350	196	582	566
annual energy bill savings compared to the no-invest[16] case (M$)	129	186	226	236
annual energy bill savings compared to the no-invest[17] case (%)	17	17	22	23
annual total CO_2 emission reduction compared to the no-invest case (ktCO2/a)	350	777	818	859
annual total CO_2 emission reduction compared to the no-invest case (%)	13	30	31	33

Figure 9. Diurnal Heat Pattern of a Large Office Building for a July Weekday, CO_2 Price, High COP of 1.2, Cheap Storage



[16] Please note that the no-invest cases are not shown here and vary depending on the CO_2 price.
[17] The considered sites satisfy all their energy needs by energy purchases from the utility.

Figure 10. Diurnal Electricity Pattern of a Large Office Building for a July Weekday, CO_2 Price, High COP of 1.2, Cheap Storage



In 2020, with low PV costs as well as consideration of a CO_2 pricing scheme, our results indicate that PV and electric storage adoption can compete rather than supplement each other when the tariff structure and costs of electricity supply have been taken into consideration. To satisfy the site's objective of minimizing energy costs, the batteries will be charged also by CHP systems during off-peak and mid-peak hours and not only by PV during sunny on-peak hours.

6. Conclusions

The ongoing deregulation of the energy sector and concerns about climate change are providing incentives for small-scale, on-site generation with CHP applications to become more attractive to commercial investors. Indeed, such DER equipment has the potential to provide tangible benefits to consumers in terms of lower energy bills as well as lower CO_2 emissions as shown in this work.

The complexity of energy flows within a microgrid may inhibit the adoption of DER unless an optimization perspective is taken. By using DER-CAM, it is possible to model a typical commercial entity's DER investment and operation problem as a mixed-integer linear program that takes data on market prices, technology characteristics, end-use loads, and regulatory rules as inputs. Although the perspective of DER-CAM is that of a small user relative to the wider macrogrid, it is employed to examine the effects of wider energy policies, such CO_2 pricing schemes and energy efficiency requirements.

In this work, we estimate the CO_2 abatement potential in the California commercial sector and report the results relative to the CARB goals. The Global Warming Solutions Act of 2006 (AB 32) requires CARB to prepare a scoping plan in order to achieve reductions in greenhouse gas emissions in California and does consider CHP in commercial buildings as an option. Focusing on 35% of the commercial electricity demand, we find that buildings based on the California Commercial End-Use Survey with electric peak loads between 100 kW and 5 MW can contribute between 1 Mt/a and 1.8 Mt/a to the CARB goal of 6.7Mt/a CO_2 abatement potential in 2020. The results also show the dominance of internal combustion engines with heat exchanger even in 2020 with a CO_2 pricing scheme and lower PV costs. The dominance of internal combustion engines can be reduced when applying a generous investment subsidy of $1500/kW for fuel cells, which results in the biggest CO_2 abatement potential of 1.8 Mt/a in 2020. The work also shows that storage technologies are not selected due to their high costs.

Finally, by making storage technologies cheaper, we find that storage systems would be selected and discharge around noon hours and may also be charged by CHP systems during off-peak and mid-peak hours and not only by PV / solar thermal systems. To satisfy the site's objective of minimizing energy costs only limited amounts of solar energy is transferred to night hours.

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PG&E E-19, http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-19.pdf

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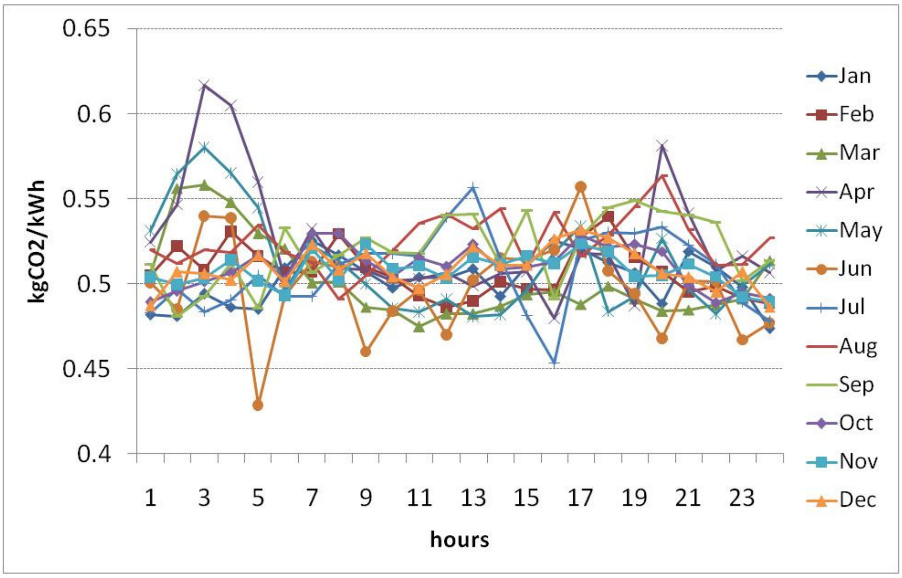
8. Appendix A: Hourly Marginal CO_2 Rates

Figure A1. Average Hourly Marginal Macrogrid CO_2 Rates in 2020



Source: Mahone et al. 2008 and LBNL calculations